

Better approaches to cleaner air from electricity generation

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ABSTRACT

The U.S. Environmental Protection Agency (EPA) developed the Clean Air Power Initiative (CAPI) as a more effective way to reduce air pollution from electric power generation. The Agency decided during the CAPI process to focus initially on nitrogen oxides (NOx) and sulfur dioxide (SOx) emissions. EPA developed a set of options that varied the level, timing, and type of approach to reducing emissions of NOx and SOx in order to meet the Clean Air Act Amendments of 1990 (CAAA) goals. The Agency analyzed the costs and emission reductions of these options using a new modeling approach. This paper describes the alternatives that EPA examined and summarizes its findings.

BETTER APPROACHES TO CLEANER AIR FROM ELECTRICITY GENERATION

During 1996, the U.S. Environmental Protection Agency (EPA) examined how the United States could use simple, market-based trading-and-banking approaches to control air pollution from electric power generation. The Agency wanted to see if these alternative approaches to pollution control could provide significant emissions reductions more cost-effectively than traditional regulatory actions -- often described as command-and-control options. This effort was EPA's Clean Air Power Initiative (CAPI).¹

Initially, the Agency examined the significance of the air pollution problems that the United States faces and the electric power industry contribution to these problems. Then EPA considered the mandates and authorities the Agency has under the Clean Air Act Amendments of 1990 (CAAA) to control power industry emissions and considered how EPA and the States could work under the CAAA to design cost-effective ways of reducing the industry's most significant air emissions. After discussions with representatives of the electric power industry, state regulatory officials, fuel suppliers, environmental groups, and pollution equipment manufacturers, EPA developed a set of options that varied the level, timing, and type of approach to reducing emissions of NO_x and SO_x in order to meet the CAAA's goals.

The Agency analyzed the costs and emission reductions of these options and did a comparative analysis of a trading-and-banking approach versus the traditional regulatory approach. The analyses led to important conclusions about how EPA and the states may want to further control air emissions from electric power generation.

1. AIR POLLUTION AND ELECTRIC POWER GENERATION

Emissions from electric power plants contribute significantly to a number of important air pollution issues. These can be categorized as: 1) adverse effects on human health from ground level ozone, particulate matter, and persistent toxic air contaminants; 2) environmental impacts such as eutrophication of coastal surface waters, wide-spread regional haze that reduces visibility, acidification of surface waters from acid deposition, ecosystem and crop damage from ground level ozone, damage to various materials from ozone and acid deposition, and ecosystem damage from mercury and other persistent toxic pollutants; and 3) climate change due to the emissions of greenhouse gases. In 1994, power plants in the U.S. were responsible for 70% of all sulfur oxide (SO_x) emissions, 33% of all nitrogen oxides (NO_x) emissions, 23% of point source emissions of direct or "primary" particulate matter (PM), 23% of anthropogenic mercury

¹EPA's paper on the Clean Air Power Initiative and supporting analyses that the Agency prepared from April 1996 to October 1996 can be found on the internet at the following web site address: <http://www.epa.gov/capi>.

emissions, and 36% of all anthropogenic carbon dioxide (CO₂) emissions².

For CAPI, EPA focused on the pollutants that are related to the first two categories of health and environmental effects noted above because these pollutants are associated with pressing regional health and environmental concerns in North America. In addition, EPA has clear statutory authority to regulate these pollutants. From a control/emissions perspective, the pollutants of greatest importance can be grouped into three categories: sulfur oxides, nitrogen oxides, and, potentially, mercury and other directly emitted toxic fine particles (see Table 1). Sulfur and nitrogen oxides emissions undergo complex atmospheric transformations that result in the formation of acidic fine particles and gases and ozone smog. The resultant mix, along with directly emitted mercury and fine particles, can be transported by weather systems over long distances and affect air and water quality and public health in areas far from where they were emitted. Because of this long range transport and the location of multiple power generation emission sources in the U.S., the resulting atmospheric and deposition problems affect broad multi-state regions.

2. REGULATORY CHALLENGE THAT CAPI ADDRESSES

The Clean Air Act Amendments of 1990 (CAAA) directed EPA to place tighter controls on power plant emissions of SO_x and NO_x to reduce acid rain, to reduce ground-level ozone, to consider the need to revise the air quality standards, and to work with states to meet revised standards. The Act directed EPA to revise its New Source Performance Standards (NSPS) and required EPA to address other issues such as air toxics and visibility, depending on the Agency's assessment of their severity. EPA will be acting on this agenda over the next 15 years.

The new controls on electric generation will occur during a very uncertain time for the power industry, compounding the challenges utilities face today in restructuring their operations to respond to the deregulation of their industry. If companies within the electric power industry could be told now what the Agency was going to do to further control their air emissions in the future and when new rules would go into effect, one major uncertainty in their future operations would be reduced. EPA's awareness of how clarity today about its future actions could alleviate some of the uncertainty that utilities face coupled with the Agency's objective to use its CAAA authorities cost-effectively to meet the Act's air quality goals led EPA to initiate CAPI.

During the CAPI process, EPA carried on a public dialog where the Agency worked with the electric power industry and other groups to develop cost-effective ways of reducing air pollution from electric power generation. A key element of that dialog was the completion of a set of analyses that provided estimates of emission reductions and costs that result from various approaches to controlling air emissions from the power industry.

U. S. Environmental Protection Agency, National Air Pollutant Emission Trends 1900-1994, Research Triangle Park, NC 1995.

TABLE 1
MAJOR REGIONAL AIR POLLUTANTS FROM POWER GENERATION

Sulfur Oxides
<p>SO_x and its transformation products (sulfates, sulfuric acid) are the primary contributors to acid deposition which makes lakes and streams acidic and damages man-made materials such as automobiles, buildings, and statues. Fine acid sulfates from SO_x form a significant fraction of particulate matter and are the major contributors to regional haze in the Eastern United States. The national ambient air quality standards for particulate matter includes all particles smaller than 10 microns in diameter (PM₁₀), and are currently under review. A growing body of evidence suggests that early mortality and other serious health effects may occur at particulate matter levels below the current standard. EPA considers reducing particulate matter exposure to be one of its highest priorities in protecting public health.</p>
Nitrogen Oxides
<p>NO_x contributes to ground level ozone, which is formed by the reaction of NO_x and volatile organic compounds (VOCs) in the presence of sunlight. Ozone causes increased asthma attacks, reduced pulmonary function, coughing and chest discomfort, headache, and upper respiratory illness. In addition to human health impacts, ozone formed from NO_x emissions adversely affects the growth of certain agricultural crops and forest species. In order to address widespread violations of the current health-based National Ambient Air Quality Standards for ozone, significant reductions in NO_x emissions will be required from both mobile and stationary sources, including power plants. Revisions to the standards are under consideration. Nitrate particles contribute to PM₁₀ nonattainment and visibility degradation, particularly in the Western United States. Deposition of nitrogen compounds into coastal estuaries (most notably the Chesapeake Bay) contributes to eutrophication and is also a significant component of acidic deposition. NO_x transformation products also contribute to gaseous and particulate phase toxic air pollutants.</p>
Mercury /Air Toxics
<p>Mercury and certain fine particle toxic elements (e.g. arsenic) are of concern because they persist in the environment. Mercury, in particular, bioaccumulates (i.e., concentrates in animals and passes up the food chain through predatory animals). Current levels of mercury in the environment are of concern to health and ecosystems. Children can be affected as well as adults, and neonatal impacts from ingestion of methyl mercury by pregnant women have also been documented. Mercury believed to be primarily from air borne deposition is linked to reduced populations of the Florida panther and the common loon. Emissions of mercury and other air toxics from utilities are described in the <u>Study of Hazardous Air Pollutant Emissions Generating from Electric Utility Steam Generating Units - Interim Final Report</u> (EPA-453/R-96-013a - October 1996). A report to Congress on mercury is currently under review by EPA's Science Advisory Board.</p>

3. CAPPS FOCUS

Given the large share of total emissions that the electric generation sector produces, EPA believes that it is very important to consider further reductions of utility emissions of NO_x and

SOx, if States and EPA are going to successfully address the ozone and fine particulate problems. The Agency also recognizes that there is sufficient information on utility emissions and knowledge of affordable pollution control techniques that are available to control NOx and SOx beyond what Title IV has required. Although fossil-fired generation units in the power sector produce a large share of the uncontrolled mercury emissions, the Agency is still evaluating the technologies that can be used to provide effective controls on these emissions.

In addition, effective strategies on controlling NOx and SOx could also help improve visibility, address eutrophication and acidification of water bodies, and contribute to the reduction in air toxics (specifically, mercury) and carbon (carbon dioxide) emissions. Therefore, EPA decided to focus initially on NOx and SOx controls in the Clean Air Power Initiative.

The Agency has also recognized through implementation of the Title IV SOx program that setting an emission cap to meet an environmental objective, allocating emission allowances to power generation units, and allowing the trading of these allowances by power plants has significant economic efficiency advantages over the traditional command and control type of regulation. The cost-effectiveness of the program is further increased by EPA allowing power generation units to "bank" early emission reductions for later use, or sale to other generators.

Because of the economic efficiency, the Agency focused on developing cap and trading/banking options for controlling SOx and NOx emissions. (See Table 2 for a list of the CAPI options.) Given the nature of the SOx problem and the existence of the Acid Rain Program, it made sense to design options that provided an emissions cap and allowed trading of emission allowances throughout the country. The summer cap would address ground-level ozone (formed primarily in the summer) while the winter cap would reduce eutrophication and acidification. For NOx, it made more sense to design options that provided summer and winter seasonal caps. EPA also hoped that a national trading scheme for NOx would keep the program simple and provide maximum liquidity for a trading market and maximum flexibility for the regulated community.

4. ANALYTIC APPROACH

To analyze the emissions reductions and costs of different options, EPA had ICF Resources Incorporated build a modelling system specifically for this purpose. The heart of the system was ICF's Integrated Planning Model (IPM), a dynamic linear programming model that selects the least-cost compliance approach for generation units providing electric power over a set time period subject to specified constraints -- in our case, pollution controls. IPM has been used by many large utilities to do capacity planning for the future. It also, has been used by the Edison Electric Institute, National Mining Association, the Department of Energy, the Tennessee Valley Authority, and EPA for similar national or regional analyses.

**TABLE 2
CAPI EMISSION CONTROL OPTIONS**

<p>Each option is a stylized approach to air emissions control. One set of trading/banking options held the SOx cap constant and varied the NOx cap levels. Another group of options focused on alternative levels and timing of lowering the SOx cap. For comparative purposes, a traditional "command-and-control" approach was also evaluated.</p>
<p>NOx-Driven Trading and Banking Options</p>
<p><u>1. Trading/Banking for NOx at .15 and SOx with 50% Cap Reduction in 2010</u> - The existing CAAA Title IV SOx program continues, but in 2010 the current cap is lowered by 50 percent. In 2000, the Title IV NOx requirements form the basis for setting summer and winter season NOx caps. Fossil generating units are allowed to trade emission allowances and bank them for future use and/or trading (as occurs now in the Title IV SOx program). In 2005, the summer NOx cap is lowered. This new cap is based on a NOx "budget" equal to .15 per MMBtus of fossil fuel that EPA forecasts will be burned by generating units in 2000.</p>
<p><u>2. Trading/Banking for NOx at .20 and SOx with 50% Cap Reduction in 2010</u> - Same as Option 1, except that the summer NOx cap in 2005 is based on .20 pounds per MMBtus of fuel use.</p>
<p><u>3. Trading/Banking for NOx at .25 and SOx with 50% Cap Reduction in 2010</u> - Same as Option 1, except the summer NOx cap in 2005 is based on .25 pounds per MMBtus of fuel use.</p>
<p>SOx-Driven Trading and Banking Options</p>
<p><u>4. Trading/Banking for NOx at .15 and SOx with 60% Cap Reduction in 2010</u> - Same as Option 1 above, except the SOx cap in 2010 is lowered by 60 percent (as opposed to 50 percent).</p>
<p><u>5. Trading/Banking for NOx at .20 and SOx with 60% Cap Reduction in 2010</u> - Same as Option 2 above, except the SOx cap is lowered by 60 percent (as opposed to 50 percent).</p>
<p><u>6. Trading/Banking for NOx at .20 and SOx with 50% Cap Reduction in 2005</u> - Same as Option 1 above, except the SOx cap is lowered in 2005 (as opposed to 2010).</p>
<p>Traditional Regulatory Control</p>
<p><u>7. The current Title IV SOx program would continue in operation, but in 2010 the current cap is lowered by 50 percent and only trading is allowed (no banking). For NOx, in 2000 the proposed Title IV requirements go into effect. In 2005, all generating units using fossil fuels must meet standards for summer NOx emissions of .15 pounds per million Btus of energy consumed.</u></p>

The modelling approach embodied in IPM allowed EPA to project future air emissions of selected pollutants and costs of electric production for a Base Case electric generation forecast that included consideration of existing environmental controls (a regulatory baseline). The Agency then ran the electric generation model after placing various types of pollution constraints on electric power generation to see the changes in selected air emissions and operating costs of electricity production after a control system was imposed.

The Agency focused on understanding the operations of fossil-fueled electric generation units in the future (i.e., where the greatest level of air emissions would result.) EPA's application of IPM considers the operations of nuclear and renewable energy sources, but does

not attribute any air pollutants to them. EPA used the best available information on macro-energy and economic assumptions, electric generation technologies, air emissions under current and future federal and state regulatory requirements, and pollution control technologies. The Agency also considered how electric generation in the future is likely to occur in a more competitive environment. (See text box for more details.)

5. RESULTS

EPA's Base Case electric power generation and air emissions forecasts are provided below. These results are followed by the Agency's estimates of air emission reductions and costs that occur for different types of control options. Finally, we provide the results of sensitivity analyses of key assumptions.

5.1. Base Case Forecast

EPA's Base Case forecast for SO_x and NO_x emissions is provided in Table 3. The table also covers mercury and carbon emissions, which the Agency wanted to also track to see if significant side benefits result from the direct control of NO_x and SO_x. The Base Case shows EPA's forecast of air emissions from the electric power industry, if no new pollution controls beyond those in place occur. The table shows increases in NO_x, mercury, and carbon emissions over the forecast period. EPA's implementation of the Title IV Acid Rain Trading Program of the CAAA lowers SO_x emissions from 1990 to 2000 and holds them in check through 2010.

TABLE 3
BASE CASE FORECAST FOR THE US
OF SELECTED AIR EMISSIONS FROM ELECTRIC POWER GENERATION

POLLUTANT	Units	1990*	2000	2005	2010
Summer Nitrogen Oxides	Million short tons	3.3	2.60	2.76	2.79
Annual Nitrogen Oxides	Million short tons	7.5	5.97	6.39	6.46
Annual Sulfur Dioxide	Million short tons	15.9	10.22	10.44	10.00
Annual Mercury	Short Ton	51.3	60.9	66.1	67.4
Annual Carbon	Million Metric tons	477	551	606	639

* This estimate is based on EPA's National Air Pollutant Emission Trends 1990-1994, October 1995 (NO_x and SO_x) and Draft Mercury Report to Congress, August 1995 (Mercury) and EIA's Annual Energy Outlook 1994, January 1994 (Carbon).

CAPI Modeling Approach and Key Assumptions

ICF set up a modeling system that used four different existing models to implement the modeling approach that EPA required. They used the Integrated Planning Model (IPM) for estimating the type of electric generation capacity and regional distribution of power generation over the forecast period. This model examines power generation on a seasonal basis. IPM has a foresight feature that factors in how power generators would consider future electric demand, fuel prices, and other variables in making their decisions to build new capacity and to comply with environmental requirements.

ICF used a comparative cost model to screen out from consideration in IPM electric generation and pollution control technologies that would not be economic during the forecast period. This kept run time of the Model manageable. ICF used its Coal Electric Utility Model (CEUM) to develop delivered coal prices and the Gas Supply Assessment Model (GSAM) of the U.S. Department of Energy to estimate delivered natural gas prices. The supply curves of the two fuel price models were added to IPM so that it generated prices suitable for the fuel demand of each model run.

Coverage

IPM forecasts cover the 48 contiguous states and the District of Columbia. All existing utility power generation units are covered in the model as well as independent power producers and other cogeneration facilities that sell wholesale power, if they were included in the North American Electric Reliability Council (NERC) data base for reliability planning. The analysis considers future capacity additions by both utilities and independent power producers.

The air emissions forecasts are provided nationally and at the NERC region and subregion level. The air emissions forecasts cover sulfur dioxide, nitrogen oxides, mercury, and carbon (carbon dioxide) emissions.

Macro Energy and Economic Assumptions

EPA considered that the ongoing deregulation of utilities will make electric generation more competitive -- plant operators will be working harder to control or reduce costs and to cap, or lower customer prices. Therefore, the Agency used NERC's 1995 forecast, rather than the lower estimate of the Energy Information Administration (EIA), which did not fully reflect competition, to develop a generation forecast. The NERC forecast was modified to account for the electric demand reduction that should result from the President's Climate Change Action Plan. EPA assumed that utilities will build less new capacity in the future as they reduce planning reserve margins (extra capacity built to meet peak demands). In 2000-2010, they range from 15% to 20% in various NERC regions.

EPA also assumed that a 20-year trend of increasing operating availability for fossil units (less down time) will continue through 2005. Plant operators work to maintain heat rates at fossil units and those rates do not decline over time as they historically have. A small number of nuclear units that do not look like they can improve enough in the future to be competitive are retired. Power can be transferred between regions in the model at 75 percent of the First Contingency Total Transfer Capability, a sustainable transmission rate recommended by NERC staff.

Fuel Prices

EPA used recently revised coal and natural gas supply curves and transportation cost functions to develop delivered coal and natural gas prices during each model run. For the Base Case, the average delivered coal prices were \$1.13, \$0.98, and \$.089 per million Btus for 2000, 2005, and 2010, respectively. The average delivered natural gas prices were \$2.15, \$2.37, and \$2.42 per million Btus over the same years. Oil prices were \$20, \$22, and \$24 per barrel over the same years.

Electric Generation Technology

EPA made assumptions on the efficiency and costs of installation and operation of all the electric generation technologies that it believed would be economically viable over the next 15 years. Most of the assumptions were based on the Energy Information Administration's estimates in the Annual Energy Outlook 1996 in conjunction with work done by the Tennessee Valley Authority. The Agency used EIA's approach to electric generation technology improvements that result from "learning-by-doing" to factor in performance and cost improvements over time. Repowering of coal and oil/gas steam to natural gas combined-cycle and integrated gasification (of coal) combined-cycle and life extension of fossil facilities were considered.

Regulatory Baseline

Electric generation units are constrained to meet applicable State NO_x and SO_x emission rate requirements, such as Reasonably Available Control Technology (RACT), but not Phases II or III of the Ozone Transport Commission's NO_x Memorandum of Understanding. New capacity must comply with EPA's New Source Review and New Source Performance Standards. Compliance with the existing requirements of the Title IV SO_x program and the NO_x Phase I rule standards are also part of the baseline.

Pollution Control Technology

EPA used engineering estimates of performance and costs prepared by Bechtel Corporation for low NO_x burner, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and gas reburn technologies that could be used at coal-fired and oil/gas-fired units for NO_x control. No improvements in performance or costs over time were assumed. The Agency used information from the Electric Power Research Institute to update its performance and cost functions originally used in analysis supporting the Title IV program of the CAAA in 1991 for SO_x controls (scrubbers). An assumption was made that control costs would decline 20 percent by 2000 in keeping with the recent trend. To reduce SO_x emissions, coal-fired units can either employ scrubbers, or switch to lower sulfur content coals, or to natural gas.

Figure 1 shows the electric generation forecast on which the Base Case air emissions are based. Coal will continue as the dominant fuel for electric power generation. Natural gas use in combined-cycle units will have an increasing role in power generation to meet growing electricity demand. Nuclear power generation will decline. There will be little change in renewable sources of power.

5.2. Emission Reductions and Costs of Control Options

EPA analyzed three groups of options: trading and banking options with alternative summer NO_x emission caps and a fixed SO_x emissions cap, alternative SO_x caps and alternative timing of the lowering of the SO_x cap with the NO_x summer cap held in most cases to the same level, and a traditional regulatory approach. EPA conducted sensitivity analyses for key assumptions. The results from each set of analyses are presented below.

5.3. NO_x-Driven Trading and Banking Options

Figure 2 shows the national summer NO_x emission reductions from each option compared to the Base Case for the NO_x-driven options. Each of the options provides substantial early reductions as plant operators bank emissions for later reductions. In 2005 and 2010, summer NO_x reductions from the Base Case projections range from 34 percent to 56 percent and 54 percent to 66 percent, respectively. Figure 3 shows how the emissions reductions are widely dispersed geographically in 2005 (a similar pattern also exists for 2010). There are substantial reductions that occur in the mid-West, mid-Atlantic, and Southeast states. Reductions in these areas are critical to addressing the ozone problem in non-attainment areas.

The annual costs of each option are shown in Table 4. The jump in costs between the NO_x .20 pound option and .15 pound option is due to the increase in the use of selective catalytic reduction technology to meet the lower emissions cap. However, the vast majority of units will not be using this technology to comply. This is illustrated in Figure 4.

TABLE 4
ANNUAL COSTS FOR NO_x-DRIVEN OPTIONS
(Billion 1995 \$)

Basis for Summer NO_x Cap	2000	2005	2010
.15 pounds of NO _x per MMBtus	\$ 1.3	\$ 2.5	\$ 4.0
.20 pounds of NO _x per MMBtus	\$ 0.9	\$ 1.8	\$ 3.2
.25 pounds of NO _x per MMBtus	\$ 0.7	\$ 1.3	\$ 2.9

Figure 1
Electric Generation - Revised Base Case
(Billion KWH)

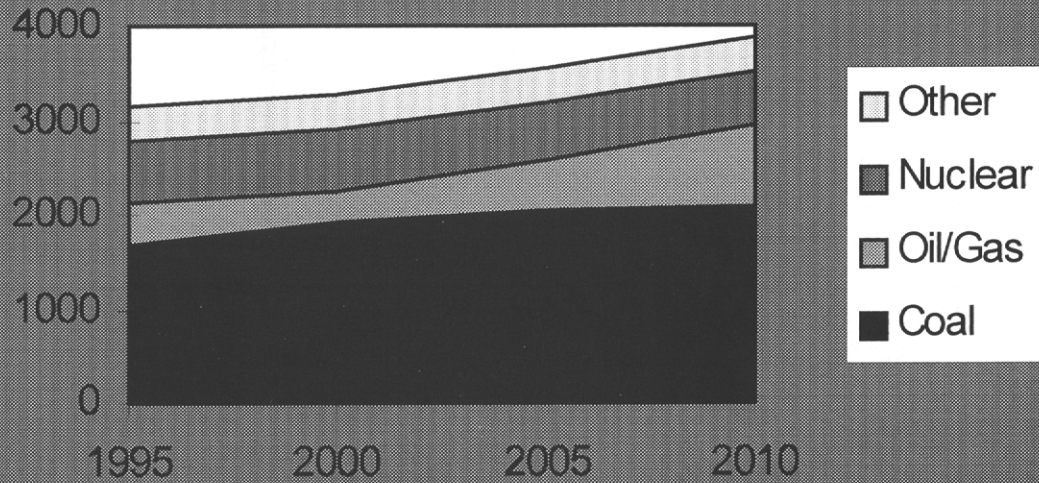


Figure 2
Comparison of Summer NOx Emissions with With
NOx-Driven Options - (Million tons)

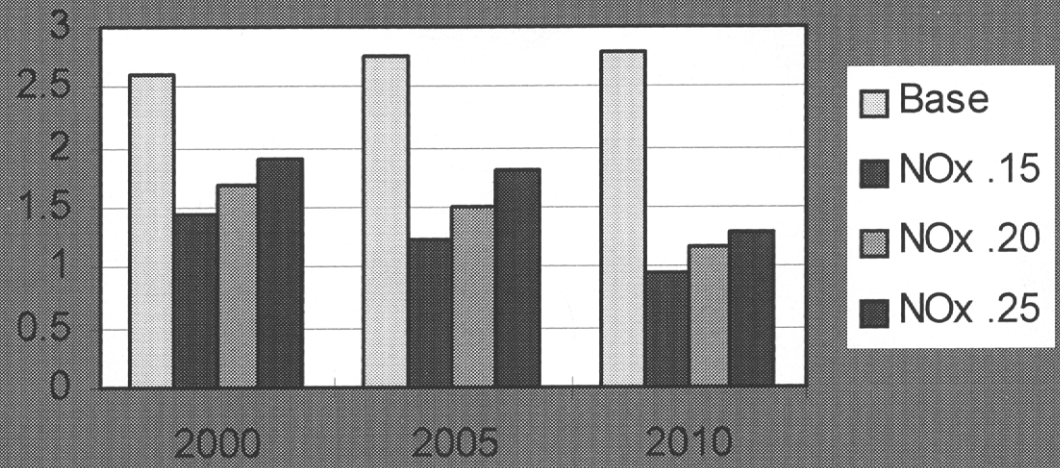


Figure 3
Comparison of Summer NO_x Emissions in 2005 for .15
and .25 Options

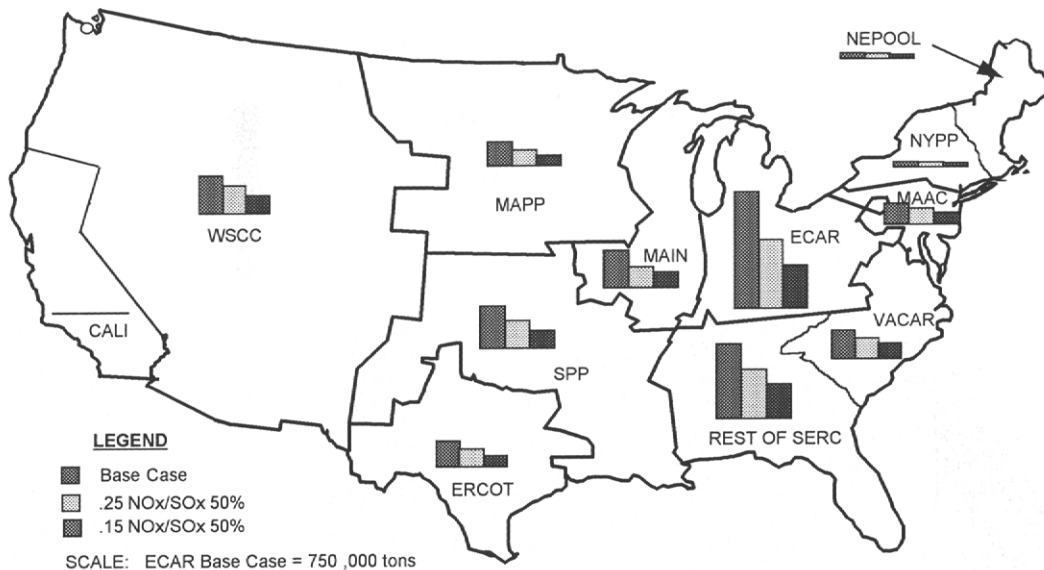


Figure 4
 Trading/Banking Is Flexible - Coal-Fired Units under .15 NO_x/50% SO_x
 Reduction (GW Capacity)

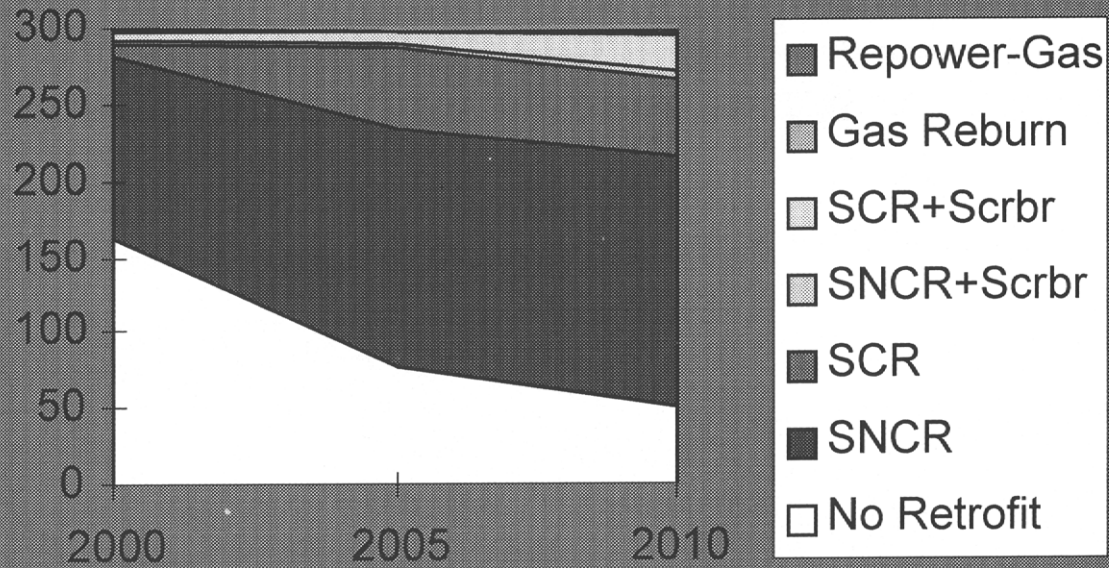
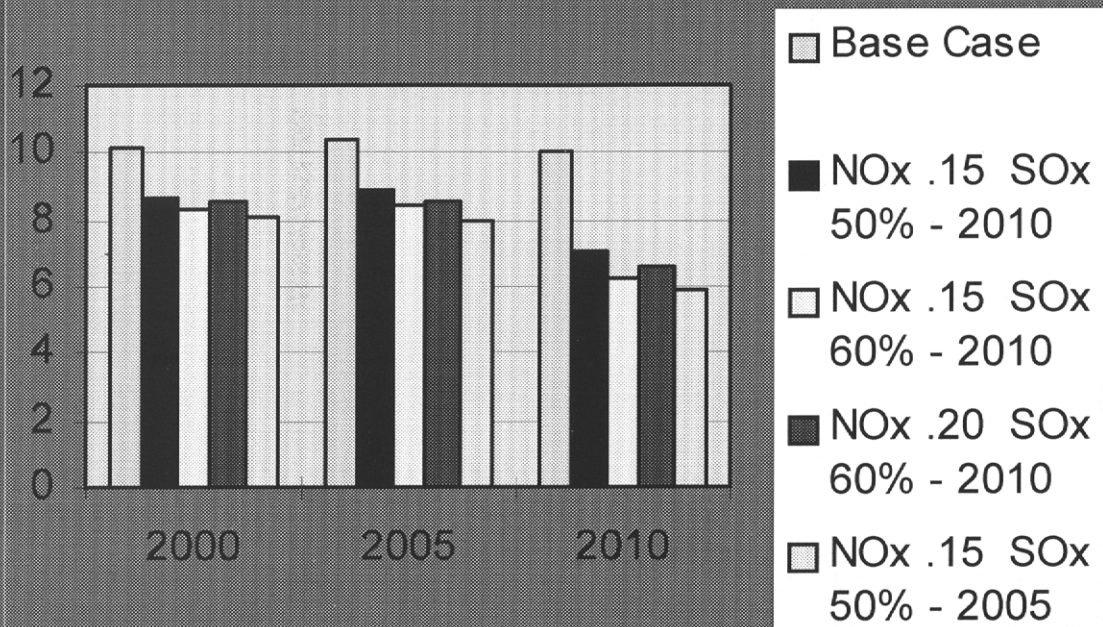


Figure 5
 Comparison of SOx Emissions in the
 SOx-Driven Options - (Million tons)



5.4. SO_x-Driven Trading and Banking Options

Figure 5 shows the national SO_x emission reductions from each SO_x-driven option compared to the NO_x .15 and SO_x 50 percent cap reduction in 2010. Although in one option the SO_x cap is moved forward to 2005, the emission reduction is not that dramatic in that year. This is because the freedom to bank and trade emissions reductions leads generation units to make and bank early reductions and withdraw them in a manner that smooths out SO_x emission reductions over time. This is a more economical compliance strategy than a making a more abrupt reduction in 2005 when the capped emission level is reduced.

The annual costs for the SO_x-driven options appear in Table 5. The table shows that its more costly to move the cap reduction forward (from 2010 to 2005 for a 50 percent reduction) than to reduce the cap level (from 50 percent to 60 percent in 2010). As we saw with NO_x, the SO_x emission reductions in these options are widespread throughout the country. The greatest reductions occur in the Eastern US where most of the emissions that affect urban areas exist.

TABLE 5
ANNUAL COSTS OF SO_x-DRIVEN OPTIONS
(Billion 1995 \$)

Summer NO _x Cap/SO _x Cap Reduction	2000	2005	2010
.15 NO _x /60% Reduction in SO _x Cap in 2010	\$ 1.4	\$ 2.6	\$ 4.7
.20 NO _x /60% Reduction in SO _x Cap in 2010	\$ 1.0	\$ 2.0	\$ 3.7
.15 NO _x /50% Reduction in SO _x Cap in 2005	\$ 1.5	\$ 2.9	\$ 5.0

5.5. Traditional Regulatory Approach

The best way to appreciate the benefits of the trading-and-banking options is to compare them to the traditional command-and-control approach. EPA did this by constructing a traditional option that was based on the same type of objectives as one of the trading and banking options. The Agency compared the Trading/Banking for NO_x at .15 and SO_x with 50% Cap Reduction in 2010 (Option 1) to an option where unit-specific rates of .15 pounds of NO_x per MMBtu are set in 2005 for the summer and the Title IV SO_x emissions cap is reduced by 50 percent in 2010 and banking is no longer allowed.

The trading and banking option has 27 percent lower summer NO_x emissions than the traditional regulatory approach in 2000. In 2005 and 2010, the traditional approach produces 38 percent and 21 percent lower summer NO_x emissions, respectively. For SO_x, the trading/banking approach has 22 percent and 19 percent lower emissions than the traditional option in 2000 and 2005, but is 56 percent higher than the traditional approach in 2010.

The annual costs of the two options are compared in Table 6. In 2000, the traditional approach is less costly as some plant operators decide not to add scrubber units and switch coals to make as many early emission reductions, since they can not use the emission allowances banked after 2010. However, in 2005 and 2010, the trading and banking option is much less expensive. On a net present value basis, from 2000 through 2010, the total costs of the traditional approach are more than 50 percent greater than the total costs of the trading-and-banking approach.

TABLE 6
ANNUAL COSTS OF TRADITIONAL VERSUS TRADING/BANKING APPROACH
FOR A NO_x SUMMER EMISSIONS CAP BASED ON .15 AND A
50 PERCENT REDUCTION IN THE TITLE IV SO_x CAP IN 2010
 (Billions 1995 \$)

Approach	2000	2005	2010
Traditional Regulation	\$ -.1	\$ 3.9	\$ 9.3
Trading/Banking	\$ 1.3	\$ 2.5	\$ 4.0

5.6. Mercury and Carbon Emissions

EPA estimated mercury and carbon emissions for each of the trading/banking options. In 2000, reductions in mercury emissions ranged from 1.7 tons to 2.5 tons of the Base Case emissions of 60.9 tons. In 2010, reductions in mercury ranged from 6.7 tons to 10.2 tons of the Base Case emissions of 67.4 tons. Carbon emission reductions in 2000 ranged from 2 million metric tons to 5 million metric tons from the Base Case emissions of 551 million metric tons. In 2010, carbon emission reductions ranged from 29 million metric tons to 43 million metric tons from a Base Case of 639 million metric tons of carbon emissions.

5.7. Sensitivity Analyses

EPA conducted sensitivity analyses of several key assumptions in the Base Case to see the difference the changes made in the forecast of NO_x, SO_x, carbon, and mercury emissions. If natural gas prices were 15 percent higher, there would not be much difference in emissions except in 2010 where there would be 30,000 additional tons of NO_x emissions. If transmission capability between NERC regions were 12 percent higher in 2000 and 50 percent higher in 2005, mercury and carbon emissions would not be much different than in the Base Case. NO_x emissions were increased by 20,000 tons, 55,000 tons, and 35,000 tons in 2000, 2005, and 2010, respectively. If the Clinton Administration' Climate Change Action Plan proved to be 40

percent less effective, the most significant change would be the additional emissions of NO_x of 122,000 tons and 63,000 tons in 2000 and 2005, respectively.

The Agency also developed a Higher Emissions Case to see how much higher future emissions would be in the future under other plausible assumptions that would lead to higher emissions. This case was premised on the potential for higher electric demand in the future, greater changes in operations to be more competitive, greater ability of generating units to send power to other regions, greater reductions of nuclear capacity, higher gas prices, and gas combined-cycle technology improving at a slower rate than assumed in the Base Case. Due to the Title IV program, the SO_x levels are similar to the Base Case. For the other pollutants, there is an increase of annual NO_x, carbon, and mercury emissions of close to 6 percent, 6 percent, and 3 percent in 2000 and close to 6 percent, 12 percent, and 13 percent in 2010, respectively.

EPA also considered how much more expensive it would be to implement one of the more aggressive trading/banking options if the Higher Emissions Case did occur. The results are provided in Table 7. The results suggest that controlling NO_x and SO_x at levels higher than our best estimate is not likely to be prohibitively expensive.

TABLE 7
COMPARATIVE ANNUAL COSTS OF THE
TRADING/BANKING FOR NO_x AT .15 AND SO_x WITH
60% CAP REDUCTION IN 2010 FOR THE BASE AND HIGHER EMISSIONS CASES
 (Billion 1995 \$)

Emissions Case	2000	2005	2010
Base Case	\$ 1.4	\$ 2.6	\$ 4.7
Higher Emissions Case	\$ 2.1	\$ 3.4	\$ 5.4

6. CONCLUSIONS

From the results of the analysis, there are five major conclusions that we believe can be drawn:

- National trading and banking approaches for summer NO_x and annual SO_x control can provide large emission reductions. By 2010, the CAPI options produced a 54 to 67 percent reduction in summer NO_x emissions and a 27 to 41 percent reduction in annual SO_x emissions below the Base Case projection.

- The NO_x and SO_x emission reductions will occur throughout the U.S. Furthermore, EPA's analysis suggests that there will be large NO_x and SO_x reductions in the areas where it can do the most good--areas that make significant contributions to the air quality of large urban areas.
- Trading and banking options offer electric generators compliance flexibility in terms of timing and options. They can install pollution control technologies, switch fuels, change dispatch/utilization, and add cleaner generation units. They also can make early "bankable" reductions and/or purchase allowances.
- The annual costs of the trading and banking options range from \$1.3 to \$2.9 billion in 2005 and \$2.9 to \$5.0 billion in 2010. If higher emissions occur in the future, there will also be higher control costs. However, our analysis suggests that these costs are unlikely to increase to levels that should limit actions to address these problems.
- A traditional regulatory approach to NO_x and SO_x control is likely to cost considerably more than a trading and banking approach. EPA's comparative analysis in CAPI showed that from 2000 through 2010, the total costs of a traditional regulatory approach are more than 50 percent greater than the costs of a trading-and-banking approach.

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